COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF KENTUCKY UTILITIES COMPANY	)	CASE NO. 8624

O R D E R

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O R D E R

On September 22, 1982, Kentucky Utilities Company ("KU") filed its notice with the Commission proposing to increase its rates and charges effective October 12, 1982. The proposed rates and charges would increase revenue by approximately $49.1 million annually, or 12.6 percent. Based on the determination herein the revenues of KU will increase by $13 million annually, an increase of 3.4 percent.

On September 23, 1982, the Commission suspended the proposed rates until March 12, 1982. Public hearings were held in the Commission's offices in Frankfort, Kentucky, on January 18-20 and 27-29, 1983.

Parties intervening in this matter included the Attorney General's Consumer Protection Division ("AG"), Lexington-Fayette Urban County Government ("Urban County"), Willamette Industries ("Willamette"), Blue Diamond Coal Company, Inc., Black River Lime Company, Clopay Corporation, Eaton Corporation, ATR Wire and Cable Company, Inc., Clark Equipment Company ("Clark"), Green

River Steel Corporation ("Green River"), Westvaco Corporation ("Westvaco") and Hancock County, Kentucky.

Briefs were filed with the Commission by February 16, 1982, and all information requested during the hearings has been filed.

TEST PERIOD

KU proposed and the Commission has accepted the 12-month period ending June 30, 1982, as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period the Commission has given full consideration to appropriate known and measurable changes.

VALUATION

KU presented the net original cost, capital structure, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates and charges. As in the past, the Commission has given limited consideration to the proposed reproduction cost.

NET INVESTMENT

KU proposed an end of test period jurisdictional rate base of $803,397,511.[1] The Commission has accepted the proposed rate base with the following modifications:

Reserve for Depreciation

KU proposed an adjustment to its depreciation expense but did not reflect this adjustment in its reserve for depreciation in determining its net investment. Thus, in accordance with past practice the Commission has increased KU's reserve for depreciation by $642,200 based on the adjustment to depreciation expense allowed herein.

Reserve for Deferred Taxes

The Commission has reduced KU's reserve for deferred taxes by $451,959. This adjustment is made to recognize the amortization of excess deferred taxes addressed in a later part of this Order and is consistent with the adjustment made to bring depreciation expense and reserve for depreciation to an end-of-period level.

Investment Tax Credits (3 percent)

KU did not propose to include the 3 percent investment tax credits in its reserve for investment tax credits in determining the rate base. Mr. John Newton, Senior Vice President for KU, stated that he thought this was consistent with the treatment in the previous cases.(2) This is not the case. The 3 percent investment tax credits were included as a reduction to the rate base in Case 8177, General Adjustment of Electric Rates of KU. The Commission is of the opinion that the ratepayers should not be required to pay a return on plant provided with these funds. Therefore, the Commission has increased the reserve by $1,769,765 to reflect the jurisdictional amount of the 3 percent investment tax credits.

Cash Working Capital

KU proposed an allowance for cash working capital based on the formula method of 1/8 of test year operation and maintenance expenses less the cost of purchased power.

Mr. Hugh Larkin, witness for the AG, attempted to reconcile KU's rate base to its capital structure. Mr. Larkin used the balance sheet method of determining his allowance for working capital. This method requires extensive studies of timing lags between payment of bills and receipt of revenues in arriving at a reasonable level of working capital. The formula method is a proven method of arriving at cash working capital and is used by a majority of the utility regulatory bodies throughout the country. The Commission concurs with KU that the formula method is simple to apply, can easily be adjusted to reflect the normalized level of operating and maintenance expenses and can produce results which are reasonably accurate.(3)

The Commission finds no evidence to support the conclusion that the cash working capital requirements proposed by Mr. Larkin using the balance sheet approach are more appropriate than the cash working capital allowance derived by the formula method. Therefore, the test year cash working capital allowance used herein is based on the formula method. In accordance with past practice the Commission has decreased cash working capital by $1,543,997 to reflect the pro forma level of operating and maintenance expenses allowed herein.

Coal Inventory

Throughout this proceeding, the Commission has been especially interested in the issue of KU's coal inventory, and for obvious reasons. Although discussion of that inventory has to do with hundreds of thousands of tons of coal, and with such arcane matters as number of days burn and whether the bottom portion of a coal pile contains useable material, the Commission has not lost sight of the vital issue: Coal supply is a very costly inventory which must be financed, and which is reflected in customers' rates. Indeed, the Commission notes that at the end of the test period the KU balance sheet reflected a coal inventory valued at $62,738,016.

The coal inventory of 1,404,251 tons at the end of the test year equates to a 109 days' supply of coal, based on KU's projected generation requirements as determined in Administrative Case No. 231, Contingency Plans for Emergency Procedures During an Energy Shortage. This exceeds KU's optimum coal inventory, which is 60 to 90 days. The June 30, 1982, coal inventory was the highest level at any time during the test year.

KU has stated that its goal is to maintain a coal inventory of 60 to 90 days, but that inventory levels are more appropriately determined on a tonnage basis rather than a calculation of days burn.[4] Further, KU discussed several factors considered in determining its optimum coal inventory range, which included potential labor problems, adverse weather conditions, and potential transportation problems.[5] The Commission's objective is to obtain a proper matching of revenues and expenses within the test year. Therefore, the Commission is of the opinion that the utilization of the test year burn rate is more appropriate than the methodology developed using the emergency procedures prescribed in Administrative Case No. 231.

Using the 13-month average test period burn rate of 11,298 tons per day,[6] the June 30, 1982, inventory level equates to a

124-day's supply which is substantially above the upper limit of KU's normal seasonal inventory range of 90 days. Further, using the 5-year average burn rate of 10,841 tons per day,[7] the June 30, 1982, inventory level equates to a 130-day's supply.

It is a principle of sound business management that an inventory must be managed, not left to its own device, nor ignored as something that will take care of itself, but managed. It must be maintained within a range that reflects a sensitivity not only to the dangers of too small an inventory, but also to the unnecessary costs of too large an inventory.

The Commission believes the record in this proceeding fails to show that KU does in fact manage its coal inventory--fails to convey the conviction that KU is sensitive to the fact that excessive coal inventory imposes an excessive and unnecessary cost on ratepayers.

The Commission finds it questionable that KU should contend it needs a coal inventory as great as 90 days. Indeed, during the test period conditions were present that should have encouraged KU to seek a minimum inventory: Considerable slack demand in the coal industry made additional supply readily available, and high interest rates made it very costly to carry coal inventory.

The Commission wishes to point out that in Case No. 8429, General Adjustments in Electric Rates of Kentucky Power Company, Kentucky Power sought Commission approval to include in customer rates the cost of financing a 70-day coal inventory. The Commission determined that during the test year actual inventory had averaged 46 days, and approved rates which reflected a 60-day coal inventory.

In the current KU proceeding, in arriving at appropriate rates, the Commission is accepting a coal inventory of 1,016,820 tons, which is an inventory of approximately 90 days at a daily burn rate of 11,298 tons, which was the 13-month average for the test year, or approximately 94 days at a daily burn rate of 10,841 tons, which was the average for the most recent 5 years. Priced at the year-end average of $44.677 per ton, this allowed inventory level reduces the total company rate base by $17,309,549. This results in a jurisdictional adjusted level of $38,599,687. The Commission wishes to make it clear that the 90-day inventory is an interim figure, and that in its next general rate case the burden will rest with KU to show why customers should be obligated to pay rates which include the cost to finance a coal inventory which exceeds 75 days.

The Commission believes the 75-day inventory is also an interim level. In subsequent proceedings the burden will rest on KU to demonstrate why its coal inventory should not be reduced below 75 days.

The Commission wishes to repeat earlier observations. For a major electric utility, the cost to finance coal inventory is considerable. Further, a fundamental goal of management is inventory control. In competitive enterprises, managers ignore inventory control at their peril. The Commission would like to be convinced that the managers of KU demonstrate that same level of sensitivity to inventory control.

Utilities come before this Commission with depressing regularity to seek approval for higher rates. A regular feature of their lament is that much is beyond their control. Certainly, some important considerations--e.g., interest rates--are beyond their control. But this only makes it all the more important that utility management exert the utmost control over those factors which utilities can control. Coal inventory is such a factor, and in this important regard the Commission intends to make every effort to assure that utility management recognize--and act upon--their responsibility and discretion in this important area.

CWIP on Hancock County

The Commission has reduced KU's jurisdictional construction work in progress ("CWIP") by $6,425,890 to exclude the costs incurred through June 30, 1982, associated with the Hancock County Generation Station. This adjustment is discussed in a subsequent section of this Order.

The Kentucky jurisdictional net original cost rate base is determined by the Commission to be as follows:

Plant in Service	$ 1,001,609,497
Construction Work in Progress	150,184,487
Total Utility Plant	1,151,793,984
Add:	
Materials and Supplies	$ 7,282,850
Fuel Inventory	38,599,687
Prepayments	576,233
Working Capital	23,309,204
Subtotal	$ 69,767,974
Less:	

Reserve for Depreciation	$	287,237,639
Reserve for Deferred Taxes		94,096,560
Reserve for Investment Tax Credit		59,006,557
Customer Advances		1,863,446
Subtotal	$	442,204,202
Net Original Cost	$	779,357,756

Capital Structure

Mr. Newton proposed a jurisdictional target capital structure of $775,146,609 that contained 40 percent common equity, 12.5 percent preferred equity and 47.5 percent long-term debt.(8) He maintained that KU's actual end-of-test-year capital structure, containing 35 percent common equity, 11.4 percent preferred stock, 2.3 percent short-term debt and 51.3 percent long-term debt, had a high degree of leveraging and was not adequate to support AA credit ratings.(9) Since the end of the test year, KU has made several changes in its financing. In August, 1982, KU issued $25 million of preferred equity(10) and in January 1983 it issued 1.5 million shares of common equity.(11) At the hearing, KU submitted updated exhibits which showed the effects of the financing after the end of the test year. Proceeds from the sale of short-term debt were used to retire portions of bank notes and proceeds from the sale of preferred and common equity were used to retire most of KU's short-term debt,(12) with the result that common equity increased to 38.1 percent of total capital.

Mr. Larkin proposed using the actual end-of-test-year capital structure containing 34.76 percent common equity, 11.3 percent preferred stock, 50.64 percent long-term debt, 2.29 percent short-term debt, .52 percent customer deposits and .22 percent investment tax credits.(13) He urged the Commission to reject the target capital structure because it was more expensive to the ratepayer than the actual capital structure.(14)

KU was unable to quantify the savings to the ratepayer should the Commission adopt the target capital structure.(15) The target capital structure would replace lower cost debt capital with relatively higher cost equity capital. This would increase the cost of capital to the ratepayer. KU's debt to equity ratio has not significantly deteriorated since 1972. In the historical period since 1972, the ratio of earnings to long-term debt expense has never been higher than during the 12 months ended June 30, 1982.(16) Therefore, the Commission is of the opinion that a capital structure containing 38.1 percent common equity, 13.4 percent preferred equity, .1 percent short-term debt and 48.4 percent long-term debt is reasonable.(17) This capital structure reflects the issuance of common and preferred equity and the retirement of debt after the test year. In allowing this capital structure, the Commission is of the opinion that KU's common equity ratio has reached the upper limit of a prudent range. Increasing the common equity ratio beyond this point would impose an unduly expensive capital structure on the ratepayers.

The Commission regularly is assured that dire consequences will follow a reduction in a utility's bond rating, and that a lowered rating will manifest itself in higher borrowing costs and thus higher rates for the company's customers. The Commission wishes to point out what should be obvious. Since the companies which voice their concern about lowered bond ratings propose only one method to prevent this development--higher rates to their customers--the question is not whether customers pay higher rates, but when and how much higher. The Commission believes that if companies wish to advance this argument, they have an obligation to accompany it with a competent financial analysis, which none has undertaken. The Commission believes there might be a "cost-minimizing" capital structure for a company, but that determination of the cost-minimizing capital structure is too important and complex to be left to intuition or conventional wisdom.

The Commission has determined KU's capital structure for rate-making purposes to be as follows:

	Amount	Percent
Common Equity	$ 287,506,736	38.1
Preferred Stock	101,117,855	13.4
Long-Term Debt	365,231,655	48.4
Short-Term Debt	754,611	.1
Total	$ 754,610,857	100.0

In accordance with the determination in the previous section regarding the revaluation of the coal supply, the Commission has reduced KU's jurisdictional capital structure by $14,109,862 to reflect the lower level of inventory and the weighted average price. Moreover, the Commission has reduced capital by $6,425,890 to eliminate the Hancock project as discussed in a subsequent section of this Order.

Reproduction Cost

KU presented the net current cost rate base in Newton Exhibit 3. In determining the current or reproduction cost rate base KU estimated the value of utility plant in service and construction work in progress at the end of the test year and applied the same additions and deductions as proposed in the net original cost rate base. The resulting total reproduction cost is $2,153,997,768. The Kentucky jurisdictional portion of the reproduction cost, using an allocation factor of 84.8 percent, would be $1,826,617,051.

REVENUES AND EXPENSES

In Newton Exhibit 4 to the application, KU proposed numerous adjustments to the test year operating revenue and expense. The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications:

Transmission Rental Expense

KU proposed an adjustment of $1,044,361 to annualize the transmission rental expense for facilities rented from the Tennessee Valley Authority ("TVA") and Old Dominion Power ("ODP"). These facilities were required to support the Mountain Division of KU and ODP and to interconnect with a 500 KV line being built by TVA from the Tennessee-Virginia state line at Phipps Bend to the Kentucky-Virginia state line by way of Pocket, Virginia. This interconnection provided a means for bulk power transfers between KU and adjoining electrical generating utilities and also improved the service reliability to the Mountain Division.

In response to the first AG request, Item 8, KU stated that this adjustment was overstated by $25,146 due to amounts inadvertently excluded from the actual booked expenses for the test period. This results in an adjusted proposed increase in transmission rental expense of $1,019,215.

The Commission recognizes that KU's customers derive the benefits of increased reliability from the completed portion of the 500 KV transmission line which connects the ODP Pocket substation with the TVA Phipps Bend substation. The Commission further recognizes that there will be additional benefits from increased reliability of service after the 500 KV line is extended to Pineville from the Pocket substation. However, the Commission is of the opinion that the benefits also accrue to the customers of ODP and the rental expense should be shared accordingly. In the absence of a quantification of the benefits and attendant expenses the Commission is of the opinion that the allowable rental expense for rate-making purposes should be based on the ratio of the KU Mountain Division's coincident peak demand to the sum of the peak demands of ODP and KU Mountain Division.(18) This method results in the allocation of $711,490 of the total annualized expense to ODP and $445,426 to Kentucky jurisdictional expenses.(19)

If KU can provide evidence in support of an allocation of expenses between the Kentucky retail customers and ODP associated with the Pocket substation, then such evidence should be presented in a petition for rehearing.

Kentucky-Indiana Pool Transaction

KU proposed an adjustment of $3,947,389 to increase other power supply expense due to the termination of the unit power sales provisions of the Kentucky-Indiana Pool ("KIP") Agreement on March 31, 1982. KU was a net seller of power to other KIP members during the first 9 months of the test year. In accordance with the Uniform System of Accounts the KIP power sales were recorded as a reduction to other power supply expense.

The AG recommended that KU's proposed adjustment be disallowed because KU has the ability to offset lost unit power sales with reduced capacity purchases or new sales agreements. The AG further contended that it is difficult to identify prospective power sales or reduced purchases which will have the effect of offsetting lost sales.

KU stated that under present conditions there is no market for long-term power sales commitments of available capacity in any sizable amounts and that it is monitoring this situation on an ongoing basis. Had the KIP not been terminated, it is probable that KU would have been required to purchase pool unit capacity during 1982-83.[20]

From the evidence of record in this case and other recent electric utility cases there is very little if any potential for additional firm power sales. The Hancock generation plant has once again been deferred, the Jackson Purchase load will be lost in 1984 and intersystem sales have declined since the test year. An offsetting adjustment to KU's lost capacity sales for expected increased sales or reduced purchases is not known and measurable at this time. Therefore, the Commission is of the opinion that KU's adjustment is appropriate and that the AG's adjustment should be denied. The Commission strongly urges KU to make every possible effort to increase its sales to other systems and to seek measures to offset these lost sales.

EPRI and EEI Expenditures

During the test year, KU paid $1,500,557 in industry association dues to the Electric Power Research Institute ("EPRI") and $204,361 to Edison Electric Institute ("EEI"). KU charged the total of these expenses to the Kentucky retail jurisdiction because of the position taken by the Federal Energy Regulatory Commission ("FERC") in KU's last rate case. Mr. W. B. Bechanan, President of KU, stated that the FERC did not allow the EPRI dues as an expense in the wholesale cost of service. The wholesale customers can be members of EPRI and the derivation of the annual membership dues is based on retail sales. Mr. Bechanan further stated that he was not aware whether the wholesale purchasers from KU were members of EPRI. Mr. Bechanan stated in his rebuttal testimony that KU was modifying its FERC filing to include a portion of the EEI dues in the wholesale cost of service. However, KU did not propose to allocate any of the EPRI dues to the wholesale cost of service in its filing with the FERC. Mr. Bechanan agreed that EPRI activities are of benefit to the operations of the total company. Therefore, the Commission finds that an allocation of both EEI and EPRI dues should be made in this case. As the basis for this allocation the Commission will use the labor allocation factor which KU proposed for allocation of the EEI dues in the FERC filing. Thus the Commission has allowed $1,359,805 for EPRI and $185,192 for EEI expenses.

While these amounts are considerable, there is no question that the electric industry is facing conditions today that call for research and development on a substantial scale. The Commission concurs with KU's position that:

> Research and development is difficult to measure in terms of future benefits. It is essential for the electric industry in this age of rapidly advancing technology, yet it is beyond the means of individual companies such as KU. The most effective and efficient approach is through pooling of resources through membership in EPRI. . . Often the benefits, while of industry-wide application, cannot be measured directly, such as the design of new or improved products manufactured by suppliers. EEI conducts studies, provides information and other support services which are utilized by the Company in practically all of its functioning departments,. . .(21)

However, merely belonging to research and development organizations does not benefit the ratepayers. The utility member must take advantage of the results of the research and of the assistance and guidance that can come through membership. Although KU continues to pour millions of dollars into these organizations, it has not made any cost-benefit analysis. On the basis of this record, it has to be concluded that the quantifiable benefits of membership in these organizations are nominal in proportion to the annual membership dues. The Commission is unable to determine whether KU's lack of evidence regarding cost savings and benefits is due to its inability to measure these benefits or its failure to take maximum advantage of the services and benefits provided by these organizations.

The Commission believes that if KU were operating in a competitive environment -- if in response to disappointing financial results it did not have this Commission and captive customers to turn to -- KU would display more diligence concerning its payment to EEI and, especially, to EPRI.

In future cases, KU must present clear documentation of the benefits available through membership, and of its utilization of these benefits. The Commission is also concerned that a substantial portion of the EPRI dues goes for research in the nuclear area which is of no direct concern in Kentucky. In future rate cases KU must document whether it could receive all non-nuclear related benefits if it reduced its dues by the portion related to nuclear research.

Accelerated Recovery of Excess Tax Deferrals

Effective January 1, 1979, the maximum corporate tax rate was reduced from 48 to 46 percent. This tax rate reduction poses the question of proper accounting for the taxes deferred prior to 1979 at 48 percent which will be flowed back at the 46 percent rate which in theory reduces the tax liability.

In the information request of October 27, 1982, Item 4, the Commission asked KU to provide the amount of excess deferred federal income taxes resulting from the reduction in the corporate tax rate as of the end of the test year. KU's response was that the reduction in the corporate tax rate did not result in any excess deferred federal income taxes because the overall deferred tax provision is deficient as a result of an understatement in years when the federal tax rates were greater than 46 percent.

The federal tax laws require regulatory commissions to normalize, for rate-making purposes, the income tax effects of differences between book and tax depreciation arising from use of accelerated depreciation for tax purposes. Thus, in the initial years of an asset's life the book tax expense for rate-making purposes is greater than the actual federal tax liability. In the later years, the book tax expense is less than the actual tax liability. Thus, the income taxes deferred on differences between book and tax depreciation prior to January 1, 1979, were provided at a 48 percent tax rate. Based on existing tax rates, the actual tax liability will be paid at a 46 percent tax rate when these differences reverse.

The theoretical argument for providing deferred taxes is that the ratepayers should be required to pay a normalized level of income tax expense through rates. The normalized level is based on the tax rate in effect at the time the deferral occurs. An assumption inherent in computing the amount of deferred taxes provided is that the tax rate will not change. However, the tax rate has changed. Thus, the difference between the amount deferred at the 48 percent rate and the amount to be paid at the 46 percent rate can be characterized as excess deferred taxes.

As a result of the request for the amount of excess deferred taxes, KU proposed a counter adjustment to increase the provision for deferred taxes. KU contends that this adjustment is consistent with the regulations of the FERC and labeled it "the FERC 144 adjustment." On November 17, 1982, KU filed an amended FERC 144 adjustment which will be discussed in a subsequent section of this Order. Mr. Price stated that the effect of the tax rate change was reflected in this adjustment.[(22)] Thus, KU never provided the amount of excess tax deferrals resulting from the change in federal income taxes.

The AG calculated the excess in the deferred account due to the tax rate change by multiplying the deferred tax balance in Account 282 for the year ended December 31, 1978, of $71,659,986 by the difference in the tax rate (48 percent - 46 percent) and dividing this amount by 48 percent. This resulted in an overstatement in the deferred account of $2,985,832, which was further reduced by 11.67 percent (23) to reflect reductions subsequent to 1978 assuming that it was being flowed back ratably over a 30-year life. The Commission is of the opinion that it is more appropriate to use the composite depreciation rate of 3.49 percent to estimate the amount of flow-back which results in an excess of $2,620,963 at the end of the test period. KU did not refute this calculation and offered no alternative determination of the excess provision for deferred taxes resulting from the tax rate change.

The AG recommended that the Commission credit surplus deferred taxes to the cost of service over a 5-year period to amortize this excess. KU contended that should the Internal Revenue Service ("IRS") consider the more rapid amortization proposed by the AG to be a violation of normalization accounting rules, KU and its customers could lose accelerated depreciation deductions. (24) The IRS has refused to rule on this issue. (25) The Commission finds no basis for KU's position.

The Commission concludes that the AG's recommendation of an accelerated amortization of the excess deferred taxes should be adopted. Therefore, the Comission will decrease jurisdictional deferred federal income taxes by $451,959.(26) A corollary adjustment has been made to reduce accumulated deferred taxes to recognize the first year's amortization, which has the effect of increasing the rate base. In order that the accumulated excess deferred taxes can be readily identified in future rate proceedings, KU should transfer the excess to a separate liability account.

Moreover, the Commission is of the opinion that equity would demand an adjustment to increase operating expenses should the tax rate increase.

Labor and Related Costs

KU proposed an adjustment of $2,458,207 to reflect increases in salaries and wages, pension costs, payroll taxes and medical costs. The Commission has accepted the proposed adjustment with the following exceptions:

A. Pension Costs

KU proposed to include pension costs of $3,840,000 in determining the adjustment for pension costs, based upon an actuarial report, dated January 1, 1981, and discussions with the actuary to determine the estimated amount for 1982. However, the actual recommended employer payment on the 1982 actuarial report was $3,379,158.(27) Therefore, the Commission has reduced test year actual pension expense by $207,939. This amount reflects the amount that should have been capitalized for the test period as discussed in a subsequent section.

B. Payroll Taxes - Unemployment Taxes

KU proposed an increase of $180,658 in jurisdictional unemployment taxes. In determining this adjustment, KU used base wages of $9,000 and a tax rate of 3.4 percent. However, the actual taxes expensed during the test period were calculated using base wages of $8,000 and a rate of .014 for state taxes and base wages of $6,000 and a rate of .007 for federal taxes. Mr. Fred Davis, Controller of KU, could not explain the basis for his proposed adjustment.(28) Therefore, the Commission has calculated the adjustment based on the current federal tax rate effective January 1, 1983, of .008 percent and $7,000 of base wages and the actual state unemployment tax rate and base wages for the test period. This results in an increase to test year expenses of $8,498 based on the 24.4 percent capitalization ratio.

C. Salaries and Wages

KU proposed to increase salary and wage expense to reflect increases of 10 percent for all employees effective August 1, 1981, 7.5 percent for non-union employees effective May 2, 1982, and 7.5 percent for union employees effective August 1, 1982. KU rounded the ratio of operating payroll to total payroll to 75 percent. The Commission is of the opinion that it is more appropriate to use the actual experience rate of 75.6 percent.

Mr. Larkin did not recommend a reduction to KU's pro forma labor increases. He expressed concern about the level of wages and the increases given by KU over the last several years. He recommended that pension expenses be reduced by the amount attributable to elimination of the employee contribution. In addition he recommended reducing the long-term disability insurance to actual claims paid. The Commission is of the opinion that these adjustments are not appropriate. The expenses associated with the change in the pension plan from contributory to noncontributory were allowed in Case 8177. The Commission finds no reason to reverse its decision in that case. KU's wage and salary increases and the increased benefits to its employees are commensurate with those of other electric utilities under the Commission's jurisdiction. Therefore, an adjustment is not necessary at this time. KU is advised that with inflation at a level substantially lower than in recent years and considering the overall state of the economy, the Commission expects minimal, if any, increases in KU's overall salary and wages throughout the remainder of the year. Further, the Commission places KU on notice that if it grants an excessive wage increase, its customers will not bear that portion of the wage increases found to be excessive.

Property Taxes

KU proposed an adjustment to increase property tax expense by $422,814 based on the value of taxable property at January 1, 1982. The AG recommended that KU's proposed adjustment be disallowed and that KU be directed to capitalize property taxes in the future. The Commission is of the opinion that property taxes related to CWIP should be capitalized as discussed in the next section of this Order. Therefore, the Commission has reduced KU's proposed adjustment by the amount of property taxes related to CWIP.[29] Moreover, the Commission has increased KU's proposed adjustment to reflect the current real estate tax rate.

After considering adjustments made by the Commission, the property tax expense for the test year should be increased by $245,140.

Capitalizing Overhead Costs

KU does not capitalize overhead costs associated with construction-related projects. These overhead costs include payroll costs such as pension costs, medical insurance, group and long-term disability insurance, and property taxes. KU contends that these costs are more appropriately a charge to present rather than future customers because they are not related to future events.(30) KU further contends that the revenue requirements are less than they would have been under a capitalization policy.(31) No analysis was performed in support of this statement.(32)

With regard to capitalizing overhead costs the Uniform System of Accounts prescribes that "all overhead construction costs . . .shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto. . ."(33)

The Commission finds no basis for KU to deviate from the Uniform System of Accounts. Therefore, KU should immediately begin to capitalize all payroll and property tax overhead costs. Further, the Commission has reduced the actual test year expenses by $1,507,456 to reflect the overhead costs that should have been capitalized during the test year. In determining this adjustment, the Commission applied the actual test year labor capitalization rate of 24.4 percent.

Depreciation Expense

KU proposed an adjustment of $2,225,711 to increase depreciation expense to reflect the annual depreciation expense based on the level of plant in service at the end of the test year and to reflect the additional depreciation on estimated plant additions for 6 months subsequent to the test year. In determining the net investment rate base KU did not propose to adjust plant in service to include additions subsequent to the test year. It presented no justification for its adjustment to increase depreciation expense to include depreciation on plant additions subsequent to the test year.

In its determination of year-end net investment rate base the Commission does not allow adjustments for plant additions subsequent to the test year. The Commission is of the opinion that the level of depreciation expense allowed for rate-making purposes should be based on the level of plant in service included in the rate base. Therefore, in accordance with past policy the Commission will allow $642,200 of the proposed adjustment based on depreciation on plant in service at the end of the test year.

Conservation Programs

KU proposed an adjustment of $248,565 to reflect increased expenditures necessary to implement the residential conservation service program ("RCS"), the heat pump conservation campaign, the add-on heat pump program, the general consumer education program, and the energy conservation and electrical safety school program.

KU did not offset these costs by the revenue that will be generated from the audit fee to be charged its RCS customers. Therefore, the Commission has reduced the proposed adjustment by $42,000 based on the estimated number of audits of 2,800 at $15 per audit.

Mr. Larkin recommended that the $72,640 in advertising support for the heat pump conservation program, $35,000 for the general consumer education program and $30,000 for the consumer wiring and control allowance be reduced by 1/2 or $68,820. He stated that advertising costs should be shared with local contractors and companies who stand to benefit from this advertising. KU contended that it had considered sharing these costs with dealers along with other promotional methods but had decided not to do so because of administrative costs, difficulty in controlling total expenditures, and the problems associated with proper accounting for co-op ads.

While the Commission is of the opinion that KU should actively pursue other promotional methods of advertising, it finds that the level of expenses requested herein is reasonable. Therefore, the Commission has allowed KU's proposed adjustments exclusive of the revenue offset of $42,000 for the RCS program.

Air Quality Control Expenses

The AG recommended that $89,502 in air quality control expenses be excluded from the test period. The expense represented a study that was made for a chemical waste treatment facility to comply with the regulations of the Resource Conservation and

Recovery Act. Inasmuch as this expense is no longer being incurred by KU, the Commission has made an adjustment to reduce jurisdictional operating expenses by $89,502.

Year-End Customer Revenue

KU proposed an adjustment to revenues and expenses to reflect the costs associated with the increase in the number of customers served at the end of the test period.

The AG contended in its brief that the labor-related expenses associated with the year-end customer adjustment is already reflected in KU's pro forma wage and salary adjustment and recommended that the Commission prevent double recovery of this item by deleting labor-related expenses from this adjustment.

KU's pro forma wage increase is applied to actual operations during the test year while the year-end customer adjustment reflects additional expenses associated with the additional customers as of the end of the test year. Therefore, the Commission is of the opinion that the adjustment allowed herein to reflect the increased costs associated with year-end customers does not duplicate KU's labor-related expenses associated with the year-end customer adjustment.

Additional Provision for 1974-1975 Refund

KU incurred $264,600 in jurisdictional expense which represented the difference between estimated revenues accrued as subject to refund during 1974 and the actual amount of the refund.(34) The AG recommended that this expense be excluded for rate-making purposes, citing a FERC audit dated January 12, 1979, which stated that KU had improperly recorded interest on revenues subject to refund.[35] KU had included the interest on revenues subject to refund in Account 930.2, Miscellaneous General Expenses, although the Uniform System of Accounts provides that such interest should be charged to Account 431, Other Interest Expense.

The Commission agrees with the AG and has excluded the $264,600 from test year jurisdictional operating and maintenance expenses.

State Income Tax Adjustment

KU proposed an adjustment of $565,871 to increase Kentucky state income tax expense to reflect a 2-year amortization of the difference between federal Accelerated Cost Recovery System ("ACRS") tax depreciation and that allowed by House Bill 342 enacted by the Kentucky General Assembly in 1982.

Under House Bill 342 the allowable depreciation expense for state income tax ("SIT") will be approximately 30 percent lower than the ACRS depreciation expense allowable for federal income tax ("FIT") purposes. This difference will continue through July 1, 1984, at which time full ACRS depreciation will be allowed for SIT purposes. House Bill 342 provides that the difference between allowable depreciation expense for FIT and SIT purposes can be included as a reduction to gross income on a pro rata basis over a 6-year period beginning with taxable years ending on and after July 1, 1984.

The adjustment proposed by KU would provide, through current rates, the additional SIT expense that would result from a repeal of the provision of House Bill 342 allowing pro rata amortization of the difference between allowable FIT and SIT depreciation expense.

KU stated that the intent of its proposal to increase SIT expense for rate-making purposes is to recover the additional taxes that would be due above book tax expense in the event the Kentucky General Assembly ultimately denies KU full depreciation on utility plant subject to ACRS depreciation as a deduction for SIT purposes.

No proof was introduced showing that the difference between allowable depreciation expense for FIT and SIT purposes would never be allowed for SIT purposes. Section 1(13)(b)1 of KRS 141.010 as amended states that, "The taxpayer's basis in any individual property shall be the same as the basis in such property for federal income tax purposes." Although the write-off of this expense may be over a longer period for SIT purposes than for FIT purposes the SIT liability over the depreciable life of the property should not be any greater unless this additional depreciation expense should be denied for SIT purposes.

At this time, the Commission can find no conclusive evidence which would lead it to believe that KU will not be entitled to full depreciation on its property for SIT purposes. Therefore, the Commission will deny the proposed adjustment for rate-making purposes herein.

Series P Bond Expenses

The AG recommended that expenses of $39,963 associated with the Series P Bonds be excluded from test year expenses because of their extraordinary nature. These bonds were not issued due to unfavorable market conditions. The AG contends that had these bonds been issued, the expenses would have been capitalized and amortized over the life of the bonds. KU stated that its management is seeking to meet its financing requirements on the best possible terms and, with persistent uncertainty in market conditions, the expenses of cancelled or deferred issues will continue.[36]

The Commission finds that these expenses were valid expenses of the test year and no evidence has been presented which would support a conclusion that similar costs will not reoccur. Therefore, the Commission has denied the AG's proposed adjustment to exclude these expenses. The Commission encourages KU to continue to exercise prudent judgment in seeking to meet its financing requirements.

Meter Reading Expenses and Expenses of Office Employees

The AG proposed to exclude the test year increases over the previous 12 months in Account 90203, Meter Reading Expense, of $257,212 and Account 92113, Expenses of Office Employees, of $130,697. The AG contended that KU's explanation for the increases was not sufficient or related to the subject matter. However, the Commission has reviewed the response of KU and finds it to be adequate. There is no conclusive evidence in the record that supports the AG's proposed adjustment. Therefore, the Commission finds no basis in allowing this adjustment.

Outside Services - Legal Expenses

KU reported $1,000,374 in Account 923, Outside Services, for the test year. This total included an accrual of $577,248 for legal services from the law firm of Ogden, Robertson and Marshall ("OR&M"). KU accrues annual expense for legal services provided by OR&M based on its best estimate of costs for a 12-month period. Mr. Davis stated that the basis for determining the accrual was historical experience, discussions with the law firm, and an estimate of fees that could be expected based on KU's current operations.

The goal of the Commission is to include a reasonable level of legal expenses in determining revenue requirements. The Commission has reveiwed the evidence of record and finds as follows:

(1) Prior to the hearing, the last bill that KU received from OR&M was for the calendar year 1979.

(2) Based on the testimony of Mr. Davis, it is apparent that limited records are kept by KU of the legal services received from OR&M. The only documentation KU has of services provided is the invoices from OR&M when they are received.

(3) Mr. Malcolm Marshall, senior partner in the firm of OR&M, stated that the firm does not bill KU on an hourly basis due to the breadth and varied character of the work performed for KU.

(4) The billings from OR&M for 1978 and 1979 were approximately $250,000 and $378,000, respectively.[(37)]

Based on the above findings, the Commission is concerned about KU's policies regarding the accrual for and payment of legal expenses. It appears that it would be extremely difficult, if not impossible, for KU to verify the rendition of services when the invoices are finally received. For this reason the Commission was surprised that KU's estimated accrual is within $393 of the actual billing filed with this Commission on February 18, 1982, which is 8 to 20 months after these services were provided. KU must monitor and control the costs expended for legal services. At a minimum this would require monthly invoices from all providers of legal services.

KU assigned outside services to Kentucky retail customers based on the labor allocation factor of 90.62 percent. The Commission is of the opinion that KU should directly assign those costs that can be allocated to each jurisdiction and assign the remaining costs based on the labor allocation factor. In determining the allowable legal expenses for Kentucky retail customers from the OR&M billing the Commission has included $90,050 in legal fees that are directly assignable to Kentucky retail customers and $189,545 to FERC wholesale customers. The remaining OR&M fees charged to Account 923 were then allocated to Kentucky retail and FERC wholesale customers based on the labor allocation factor.

Costs that are directly assignable to wholesale customers include legal fees associated with antitrust matters. KU contends that these costs benefit the total company. However, the

Commission finds that although these costs may benefit the total company, the litigation arose from the wholesale customers. Therefore, the Commission has excluded antitrust legal expenses of $41,187 paid to the firm of Morgan, Lewis and Pockins from jurisdictional expenses for the test period. These are in addition to the antitrust expenses excluded from the billing of OR&M.

After exclusion of the above adjustments, the Commission has allowed $689,648 in Account 923 for rate-making purposes for the Kentucky jurisdiction.

But beyond adjustments to legal expenses, the Commission has a broader concern. In this proceeding the Commission has been especially interested in KU's legal expense because it bids fair to distinguish itself as the company's fastest-growing cost. As has been noted, the billings from OR&M were approximately $250,000 in 1978, $378,000 in 1979, and $577,000 in the 12 months ended June 30, 1982. If KU finds the need for legal services to be at the level -- and increasing at the rate -- indicated by the OR&M billings, the Commission would like to be confident that the company has considered a staff attorney as a less expensive alternative to exclusive reliance on OR&M.

In addition, the Commission commends to KU's senior management and Board of Directors an article, "Kill All the Lawyers? Maybe There's an Alternative," which appeared in THE WALL STREET JOURNAL on December 13, 1982. In that article William E. Blundell, who is an attorney and corporate counsel at Homestake Mining Co., argues that a corporation's legal affairs need to be viewed as assets or liabilities, and as such need to be managed. The Commission would like to be confident that KU views its legal affairs in that context.

Interest Synchronization

KU proposed an adjustment to increase state and federal income taxes by $3,354,268 for the effects of the reduction in interest expense associated with KU's proposed target capitalization. In determining the adjustment, KU applied a long-term debt interest rate of 9.3 percent to the adjusted level of the proposed capital structure. The Commission has modified this adjustment to reflect the projected interest cost on the adjusted capital structure allowed herein and the allowed cost rates. The resulting adjustment to income taxes for the Kentucky jurisdiction is $3,552,133. This adjustment illustrates our concern with any additional increase in the equity ratio, since this adjustment is totally a result of increased equity ratios and is in addition to the higher return required by equity.

FERC 144 Adjustment

KU proposed an adjustment to increase federal and state income tax expense by $321,307 to reflect the recovery over a 5-year period of a calculated deficiency in the deferred tax reserve. Mr. Davis stated that the proposed adjustment was necessary to make up the deficiency in the reserve for deferred taxes resulting from flow-through treatment of book and tax life differences. KU proposed a 5-year recovery period because the property was relatively old. Mr. Davis further stated that the proposed adjustment was pursuant to FERC Orders 144 and 144A, requiring utilities to include in rate filings a plan to currently recover tax benefits previously flowed through.

KU submitted a revision of its proposed adjustment as a result of a further review and analysis by its outside accountants, Arthur Anderson & Company. The revised deferred tax deficiency was determined to be $15,784,539 rather than $1,991,971 and resulted in an $889,198 adjustment based on a 15-year recovery. The difference in the two proposed adjustments is that the latter adjustment considers not only life differences, but also other timing differences such as AFUDC or payroll taxes which have not previously been fully provided with deferred taxes or depreciation. The proposed recovery period was increased from 5 to 15 years to reflect the approximate remaining life of the property relating to the deferred tax deficiency.

During the course of these proceedings the Commission and the AG have requested additional information relating to the cause of this deficiency in deferred tax reserves. KU's response has been that work papers reflecting the actual causes for the deficiency are not readily available, the information could not be generated in sufficient time to be used in these proceedings[38] and the specific causes are not important.[39] In determining the amount of the deficiency, KU used what it refers to as the "South Georgia method," which was accepted in a 1978 FERC rate case involving South Georgia Natural Gas Company, FERC Docket No. RP 77-32. In that case South Georgia Natural Gas Company agreed to discontinue its prior practice of flowing through the tax affects of timing differences and to adopt comprehensive interperiod allocation. The record reflects that this adjustment has been allowed by the FERC in other gas utility cases but KU witnesses were not aware of any electric utility cases before the FERC in which such an adjustment has been allowed.

Even though the Commission can not be certain of the validity of the numbers in KU's proposed adjustment, or the basis for the deficiency in the deferred tax reserve, the primary issue in this matter is the effect of this adjustment on the current KU ratepayers. The purported deficiency in the deferred tax reserve is a result of prior years' book tax expense being lower than it would have been under full normalization accounting. Therefore, the past customers received the full benefit of this accounting treatment which KU now seeks to recover from its present customers.

The decision of KU's management at that time was to flow through the benefits of these timing differences although this treatment would result in lower tax expenses, lower deferred taxes and lower rates to KU's ratepayers. This Commission did not require KU to flow through these tax benefits. The Commission is not persuaded that KU should be allowed to change its management decision and recover this additional tax liability from its present customers. Therefore, the Commission has denied the proposed adjustment. To allow this adjustment would constitute retroactive rate-making, which is illegal.

Unbilled Revenues

Mr. Larkin proposed an adjustment of $2,492,046 to increase test year revenues to reflect unbilled revenues. The adjustment consisted of two parts. The first part represented the difference between unbilled revenues as of June 30, 1981, and June 30, 1982, of $217,166; the second part represented the balance of unbilled revenues as of June 30, 1981, of $11,374,403. Mr. Larkin proposed to amortize this component to income over a 5-year period. The basis for the 5-year amortization was that the greatest growth period in unbilled revenues has been over the most recent years and it was more appropriate to pass these benefits through to the ratepayers who have suffered the economic hardship associated with excessive rates.

KU currently records revenue based on actual billings. It also records on an annual basis the revenues due from bi-monthly customers based on the November bi-monthly revenues divided by two. Meters read during a particular month are billed and booked in that month.[(40)] Mr. Larkin stated that KU fails to record the revenues associated with the cycle lag, which is the period between date of service and date of meter reading which he estimates at 15 days. Mr. Larkin contends that failure to record this unbilled revenue is in violation of generally accepted accounting principles which require the matching of all revenue and expense. However, Mr. Price pointed out that "a substantial majority of electric utilities report revenues on a meters read basis, and this is considered to be in accordance with generally accepted accounting principles."[41] Further Mr. Price argues that the adjustment proposed by Mr. Larkin constitutes retroactive ratemaking.

The primary reason for this adjustment presented by Mr. Larkin is that proper accounting requires matching of revenues and expenses. Furthermore, Mr. Larkin believes that if unbilled revenues had been recorded in the past the customers of KU would have benefited from lower rates for electric service. The arguments of Mr. Larkin lead the Commission to arrive at the same conclusion as Mr. Price regarding retroactive rate-making. Clearly, if rates had been lower in prior years the customers of KU would have realized an economic benefit. Mr. Price's argument that KU did not recover its full cost of service based on the allowed rate of return during those years is also valid.

In determining the reasonable revenue requirements of KU the Commission utilizes the historical test period adjusted for known and measurable changes. Therefore, the actual test year volumes of electric sales included in the billing analysis are the basis for the actual and normalized revenues. Although the sales volumes of the test period are based on billed sales rather than actual units of energy produced and delivered the sales volumes for a given 12-month period should be representative of normal sales.

Therefore, if an assumption were made that revenues for the test period were understated, a concurrent assumption would need to be made with regard to sales volume. The AG has presented no arguments that the test year sales volumes are affected by the failure of KU to accrue unbilled revenue. Therefore, the Commission finds that the revenue based on the billing analysis filed in this case is representative of test period operations and no further adjustment is necessary.

Moreover, contrary to the AG's contention that this adjustment would not be retroactive ratemaking,[(42)] in the absence of any arguments that the unbilled revenue affects test year sales volumes, the adjustment is clearly to offset excessive revenues in prior years, which would constitute retroactive ratemaking. Therefore, the Commission will not adopt this adjustment.

Fuel Clause Adjustment

Mr. Larkin proposed an adjustment of $5,698,846, to increase test year revenues to reflect the matching of fuel costs and fuel revenues recovered under the Fuel Adjustment Clause ("FAC"). Mr. Larkin contends that over- or underrecovery of fuel costs is more appropriately dealt with in the FAC hearings rather than in this rate proceeding. Mr. Larkin stated, "If such matching is not done then the base rates established would include under- or over recovered fuel costs which would be duplicated in a fuel clause hearing."[(43)] Furthermore, Mr. Larkin indicates that KU could recover underrecovered fuel costs twice or it could be denied the opportunity to properly recover these costs. After reflecting the impact of Mr. Larkin's unbilled revenue adjustment, the proposed test year fuel revenue adjustment was reduced to $3,487,822.

KU's witness, Mr. Hewett, identified a number of conceptual deficiencies in Mr. Larkin's fuel clause adjustment. Mr. Larkin used total company figures to calculate the adjustment and neglected to present the adjustment on a jurisdictional basis. He did not use true monthly KWH or dollar sales figures in his calculation of the adjustment. He failed to include KU's bi-monthly customers in the calculation of the adjustment. He did not utilize monthly bill frequencies for the test year, provided by KU, in determining recovery values. Further, he stated, "Kentucky Utilities fuel clause is a fully recovering type clause."(44) His understanding of KU's fuel adjustment clause is questionable, since there is no mechanism to allow recovery of underrecovered fuel costs and the forced outage provision in the regulation prevents KU's fuel clause from being truly classified as a "fully recovering type clause."

Therefore, the Commission finds that Mr. Larkin's calculation of the fuel clause adjustment is not acceptable. Although a proper adjustment can not be determined from the record in this case, the Commission will investigate this matter further in future rate proceedings.

RATE OF RETURN

Mr. Newton proposed an 8.73 percent rate for preferred stock and a 9.33 percent rate for long-term debt.(45) These rates were based on the adjusted amounts of preferred equity and long-term debt used to achieve the target capital structure.(46) At the hearing, Mr. Newton updated those rates to 8.95 percent for preferred stock and 9.13 percent for long-term debt.(47) Those rates reflected pro forma adjustments and actual adjustments that occurred after the end of the test year to preferred stock and long-term debt.(48)

Mr. Larkin proposed a 9.26 percent cost of preferred equity and an 8.99 percent cost of long-term debt.(49) The 9.26 percent rate reflected the issuance in August 1982 of $25 million of preferred stock.(50) The 8.99 percent rate reflected the inclusion of term loans at an 11.5 percent rate rather than the rates listed on Newton Exhibit 6, page 3.(51) Mr. Larkin assigned a 10.5 percent rate to short-term debt to reflect KU's ability to borrow at rates less than prime through the issuance of commercial paper.(52) Mr. Larkin also assigned a 6 percent rate to customer deposits.(53)

The Commission is of the opinion that a 9.26 percent rate for preferred stock, a 9.25 percent rate for long-term debt and 10.5 percent rate for short-term debt are reasonable and should be adopted for rate-making purposes. The 9.21 percent rate reflects the inclusion of the cost of the new $25 million preferred stock issue into the embedded cost of preferred stock listed on Newton Exhibit 6, page 2. The 9.25 percent rate is the embedded rate for the year ended December 31, 1982.(54)

Dr. Charles F. Haywood, Professor of Finance at the University of Kentucky and witness for KU, recommended a rate of return on common equity of 18 percent.(55) Dr. Haywood performed a comparable earnings and discounted cash flow ("DCF") analysis to develop his recommended return.(56) KU ranked 96th out of 100 comparison companies on the basis of the 1981 return on year-end common equity.(57) Dr. Haywood estimated a 5.8 percent dividend growth rate and added to that an 11.7 to 12.7 percent dividend yield to arrive at his recommended range of 17.5 to 18.5 percent.(58) He stated that the actual return KU earned on equity was about 4.5 to 5 percentage points lower than the allowed return.(59) That gap was caused by inflation and other market conditions. An 18 percent allowed return on equity would enable KU to actually earn approximately 13.2 percent on common equity.(60)

Dr. Haywood's DCF calculation had some serious limitations. He did not use the earnings retention ratio times the return on book value of equity ("BxR") method nor an historical compound growth rate to estimate KU's dividend growth rate. Instead, he estimated the future increases in KU's dividend that produced the 5.8 percent dividend growth rate, based solely on his judgment.(61) The compound growth rate of dividends for KU was 3.9 percent over the past 6 or 7 years, according to Dr. Haywood.(62) The compound growth rate of dividends was 2.7 percent from 1977 to 1982.(63) The improvement in the price of KU's stock has resulted in a market to book value greater than one. The recent improvement in the inflation rate has reduced the likelihood of a significant gap between the allowed return and the earned return on equity.

Dr. Carl G. K. Weaver, principal with M.S. Gerber & Associates, Inc., and witness for the AG, recommended a cost of equity for KU in the range of 14.3 to 15.4 percent.(64) Dr. Weaver developed that range using a DCF analysis and then used the earnings-price ratio method and the comparable earnings method to confirm his findings.[65] Dr. Weaver used the BxR method to estimate his dividend growth rate of 2.4 percent.[66] He took an 11.7 percent dividend yield, multiplied it by a 1.024 growth factor and added his 2.4 percent dividend growth rate to calculate a 14.4 percent cost of equity using the DCF approach.[67]

Mr. Don Wiggins, witness for Concerned Citizens and Businessmen of Central Kentucky, Inc., proposed an alternative rate-making method, "the net profit margin formula." The Commission responded to Mr. Wiggins in its South Central Bell Order, Case No. 8467, entered October 13, 1982. The Commission is of the opinion that its current methods serve the public interest better than would Mr. Wiggins' proposed net profit margin formula.

After considering all of the evidence, the Commission is of the opinion that a range of returns on common equity of 14.75 to 15.75 percent is fair, just and reasonable. A return on equity in this range would not only allow KU to attract capital at reasonable costs to insure continued service and provide for necessary expansion to meet future requirements, but also would result in the lowest possible cost to the ratepayers. A return on common equity of 15.25 percent will allow KU to attain the above objectives.

Rate of Return Summary

Applying rates of 15.25 percent for common equity, 9.26 percent for preferred stock, 9.25 percent for long-term debt and

10.5 percent for short-term debt to the capital structure approved herein produces an overall cost of capital of 11.54 percent. The additional revenue granted will provide a rate of return on the net original cost established herein of 11.2 percent.

AUTHORIZED INCREASE

The Commission has determined that KU needs additional annual operating income of $6,598,192 to produce a rate of return of 15.25 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes there is an overall revenue deficiency of $13,027,033 which is the amount of additional revenue granted herein. The net operating income required to allow KU the opportunity to pay its operating expenses and have a reasonable amount for equity growth is $87,071,452. A breakdown of the required operating income and the increase allowed herein is as follows:

Net Operating Income Found Reasonable	$87,071,452
Adjusted Net Operating Income	80,473,260
Net Operating Income Deficiency	6,598,192
Additional Revenue Required	13,027,033

OTHER ISSUES

Rate Design

KU proposed a rate design based on the cost of service study it filed in this case. KU requested a reduction in the number of energy steps for all rate classes, consolidation of several of the existing tariffs and varying customer charges for several of the rate classes. The Commission agrees with KU on the reduction in the number of energy steps and the proposed tariff consolidations. The Commission is of the opinion that the difference in proposed customer charges between the RS and the FERS tariffs is excessive because of the similarity of the tariffs and should be reduced in this case.

Clark disagreed with KU's proposed rate schedule for the LP tariff as to the diversity of load of customers who can be served by this rate schedule. The Commission is of the opinion that KU's proposed LP rate schedule should be accepted and that in its next rate case KU should present a more comprehensive study of the LP tariff.

The Urban County opposed the proposed rates for the street lighting tariff, in particular the new HPS tariff. The Commission has analyzed the procedure which KU has adopted to establish the new HPS tariff, and finds that the proposed rates are not fair, just and reasonable. Therefore the Commission has reduced the proposed rates in the HPS tariff by the same percentage as it has reduced the proposed rates for the street lighting tariff.

At the hearing and in its brief, the Urban County referred to retrofitting and energy cost only rates, and questioned why KU did not include a 3500 lumens HPS rate in the street lighting tariff. From the questions of the Urban County and responses of KU, there appear to be misunderstandings by both parties. The Commission is of the opinion that further discussions between the parties could resolve these differences to the best interest of all concerned.

KU proposed several changes to the charges in the rules and regulations. KU proposed to increase the reconnection charge from $9 during regular scheduled working hours and $33 for other than regular scheduled hours to charges of $15 and $51, respectively. The Commission has allowed these charges to increase only by the percentage of KU's revenue request granted in this case. KU proposed a charge of $9 to recover the cost of a special trip during which a delinquent account is collected. The Commission does not agree that a special trip charge is warranted at this time.

KU proposed a new tariff to charge $18.50 for one customer requested meter test per 12 months when the meter is found to be not more than 2 percent fast. This proposed charge consists of $3.50 to test the meter and $15 for one service trip. KU proposed its service trip charge to equal its reconnection trip charge because of their similar nature. In accordance with the Commission's reduction of the reconnection charge, the service trip charge will be similarly reduced. Accordingly, the Commission finds that $14 is the reasonable charge for the meter test. Additionally KU proposed a return check charge of $9 to cover the cost of returned checks. The Commission is of the opinion that a $5 per check charge is fair, just and reasonable.

INTERRUPTIBLE SERVICE TARIFF

KU proposed an interruptible service rate with demand charges equal to $9.80 per KVA of firm capacity, $7.80 per KVA subject to 200 hours interruption and $7.30 per KVA subject to 400 hours interruption. The proposed energy charge is 1.931 cents per kilowatt hours. The Commission accepts the tariff as proposed.

Pursuant to the Order in Administrative Case No. 203, Rate-making Standards Identified in the Public Utility Regulatory Policies Act of 1978, KU will be required to file a marginal cost of service study in its next rate case. It is the opinion of the Commission that in its next rate case KU should base the demand and energy credits for service interruption on marginal costs to accurately reflect the cost savings from load growth reduction.

RIDER S

KU proposed to increase its demand charge for Rider S from $4.31 to $5.76 per kilowatt. Rider S is the supplementary, backup or reserve rate for customers with privately-owned plant or other sources of supply. Westvaco opposed the continued inclusion of Rider S as being "contrary to the intent and purpose of section 210 of the Public Utility Regulatory Policies Act of 1978."[(68)]

The Commission is of the opinion that Rider S is a hindrance to the growth and development of cogeneration and small power production in Kentucky. Since the Commission wishes to encourage the development of alternative power sources, it will direct KU to remove Rider S from its current tariff offerings.

REVENUE ALLOCATION

KU has proposed to distribute the increased revenues granted in this case based on its historical allocation of revenue to the classes.[(69)] The AG, Green River and Westvaco did not propose an alternative revenue allocation. Clark concurred with KU's proposed revenue allocation.[(70)]

It is the opinion of the Commission that the proposed changes in rate structure, in conjunction with even minor changes in historical revenue allocations, would result in problems of rate continuity. Therefore, the Commission concurs with KU's proposed revenue allocation to the rate classes. However, the Commission reminds KU that an historical allocation of revenue is not necessarily an optimum allocation. The Commission will require KU to address with specificity the relative risk of serving each rate class in determination of class revenue requirements in future rate proceedings.

COST OF SERVICE

Pursuant to the Order in Administrative Case No. 203, KU filed a time differentiated embedded cost of service study in this case. It used the Probability of Dispatch ("POD") model developed by Gilbert & Associates for allocating production demand costs to three time periods, the winter peak, the summer peak and an offpeak period. The Proportional Responsibility method is used to allocate system transmission costs to these periods. These costs are then allocated to the customer classes on the basis of each class' coincident peak and average demand. The study resulted in approximately 55 percent of the demand costs being allocated to customer classes by average demand and 45 percent by coincident peak.

Westvaco presented an alternative cost of service study. Westvaco allocated the production and transmission capacity costs to customer classes based on contribution to system coincident peak during summer and winter months. It was not time differentiated.

Green River, Clark and Westvaco recommended that the Commission reject KU's cost of service because it was theoretically unsound,[71] discriminatory,[72] not widely accepted,[73] and based on inadequate load research.[74]

Of the two cost of service studies filed in this case, KU's study is preferable. The embedded joint production costs, to the maximum extent possible, should be allocated based on the factors which caused the investment. In explaining the generation investment dicision, KU witness Mr. Ronald Willhite, Director of Rates and Economic Research, testified, "there are [trade-offs] between the different types of units, trade-offs between capacity and energy costs and that's what we have tried, as best we could, with our model, to reflect in our cost of service model."[75] KU's embedded production costs are clearly the results of the consideration of many different factors and not solely the system coincident peak demand. If the Commission accepted Westvaco's coincident peak methodology it would clearly violate the principle of cost causation by allocating additional generation costs, caused by duration of load and not system peak, to a class which could have been served at a lower cost by peaking units. KU's study in this case better reflects the principle of cost causation and therefore is preferable to Westvaco's study.

KU has been actively involved in a load research program since 1980. This is the first rate case in which the results of that load research have played a major role. The Commission realizes it takes time for a utility to fully utilize this information in both its cost of service and rate design activities.

However, the Commission believes KU can begin to demonstrate analytically whether its rates track costs for certain rate classes. Therefore, in its next rate case, the Commission will require KU to develop the research and statistical analysis necessary to illustrate that its rate design for the LP rate class actually tracks costs.

The Commission reminds utilities and intervenors that it does not intend to adopt a single cost of service methodology. The Commission views cost of service as an important element in attaining its equity objective but, it is not the only element in rate design nor is equity the Commission's only regulatory objective. The Commission realizes that class rates of return vary according to cost of service methodology. For this reason, it encourages all intervenors to prepare and file time-differentiated cost of service studies in future rate cases and to propose alternative class revenue allocations.

PRICE ELASTICITY ADJUSTMENT

KU proposed an adjustment to reflect a revenue deficiency of $6,077,482 because of the price elasticity of its demand curve. Mr. Robert Hewett, Vice President of Rates and Contracts for KU, used multiple regression analysis to estimate the price elasticity coefficient to be equal to -.21. The elasticity coefficient was applied to the overall 11.07 percent proposed increase in rates, resulting in a 2.32 percent reduction in kilowatt hour sales.

Urban County witness Mr. Samuel Rhodes opposed the proposed revenue adjustment because KU failed to test its model statistically and misspecified the income variable and the temperature variable resulting in illogical monthly estimates for kilowatt hour sales.

KU failed to perform and provide the appropriate statistical tests necessary to confirm the validity of its proposed model.[76] Such standard statistical information as the variances of the Beta coefficients, "T" statistics, "F" statistic, Durbin-Watson statistic and the correlation matrix were not provided. Estimates from a regression model without these tests can not be assigned any statistical validity. Furthermore, without a test for statistical significance, KU has rejected microeconomic price theory by excluding the income variable from its regression model.[77] The deletion of this variable results in contradictory testimony by KU on the effects of the current recession on kwh consumption.[78] As it is the result of a statistically untested and improperly constructed model, the Commission finds that the price elasticity adjustment is found to be neither known nor measurable and is hereby denied.

But beyond the above technical considerations, the Commission in Case No. 8177 stated that the loss of kilowatt hour sales due to rate increases was a normal business risk which KU shareholders would have to bear. These risks are currently reflected in KU's allowed rate of return. To approve the price elasticity adjustment would result in shifting of risks from KU shareholders to its customers and any such shift should be accompanied by an appropriate reduction in the allowed return on equity. The Commission does not intend to transfer this business risk to consumers. In future rate cases it will not consider a price elasticity adjustment as an appropriate adjustment to revenue.

LOAD FORECASTING

In Case No. 8666, State Wide Planning for the Efficient Provision of Electric Generation and Transmission Facilities, the Commission expressed its concern with load forecasts and capacity expansion activities in Kentucky. Higher interest rates, escalating construction costs, and environmental uncertainties have continued to increase the cost of expanding generation capacity at the same time that depressed economic activity and increased conservation have added to the uncertainties surrounding the load forecasts. These events contribute to forecasting errors which result in costly modifications of construction projects.

This rate case provides the first opportunity since the establishment of Case No. 8666 for the Commission to review and analyze KU load forecasting, capacity planning and capacity expansion activities.

KU's load forecasts and forecasting methodology were sponsored by Mr. James Tipton, Director of Engineering Special Projects. Mr. Willhite provided the energy forecasts and forecasting methodology.

KU forecasts loads by statistically adjusting historical loads for abnormal weather conditions and then trending the results for the period of the forecasts. The trend results are then adjusted by Mr. Tipton for various factors such as conservation, disposable income, appliance saturation and changes in competitive fuel prices. These adjustments are neither directly quantifiable nor reproducible except by the forecaster's ability "to try to remember"[(79)] the impact of each factor. The final review and adjustments are performed by Mr. Bechanan and a committee of senior level management. They rely on historic load factors and their collective judgment, experience and intuition to derive the final load forecasts.

The Commission is concerned that KU's current forecasting methodology fails to provide or explain the underlying relationship between major external factors (e.g., conservation, disposable income) and their impact on load growth. The basic assumption underlying time-trend analysis is that the future will be like the past. The more unstable the operational environment of KU, the greater the probability that simple time trend analysis will produce forecast errors. Over the past decade KU's electric consumers have been faced with rapidly increasing electric rates and changes in relative prices of alternate forms of energy, disposable income, and attitudes toward conservation. The result has been alterations in historic electric consumption patterns. The Commission does not believe that any forecasting method would be absolutely accurate in predicting consumer behavior in such an environment. However, it does believe that a more sophisticated forecasting method would provide a better understanding of the factors that cause a forecast not to be realized. Furthermore, the use of newer forecasting methods would facilitate the consideration of different assumptions for the relevant factors. The net result of the implementation of more sophisticated forecasting techniques should be an improvement in the quality of the forecasts and a greater availability of information to enhance KU's capacity planning activities.

The Commission is aware that more sophisticated forecasting methodologies exist and are being used by electric utilities for load forecasting. KU contends that there has been a gradual evolution and improvement in its forecasting procedures. Its witness, Mr. Tipton, was reluctant to adopt a different forecasting method when he stated, "I don't want to adopt a model out of haste and make a mistake."(80) The Commission has been unable to discern the evolution and improvement in KU's load forecasting methods. Since 1977, KU has continually overestimated its load growth.(81) The Commission is concerned that the forecast errors will continue and will result in increased costs for KU's consumers.

KU's current approach to load forecasting and its effect on electric ratepayers can be illustrated by Ghent IV. In November 1979, KU's load forecast for the winter of 1984-85 was estimated to be 2605 megawatts.(82) As a result of that load forecast, KU delayed the commercial operation date of Ghent IV until October 1984. In January 1983, KU lowered its load forecast for the winter of 1984-85 for the third consecutive year, to 2239 megawatts, for a total decrease of 366 megawatts in 38 months.[83] Overestimates of load growth could not be corrected through changes in the scheduling of Ghent IV because the construction had advanced to the point where the cost of delay exceeded any savings. When Ghent IV begins commercial operation KU's projected reserve margin of 55 percent will be more than double its objective. KU's customers will be asked to pay for Ghent IV before it is needed to meet their load.

The Commission is concerned about KU's load forecasting, and about such related issues as the benefits to be realized by cost-effective conservation programing, pursuing the development of small power production and cogeneration, and the extent to which it would be economically beneficial for KU to purchase power from and/or sell power to neighboring utilities. These concerns are the heart of the Commission's belief that it has an obligation to pursue, for Kentuckians, an energy strategy that represents least cost consistent with appropriate reliability, and the further belief that the least-cost system does not exist.

To respond to these concerns and beliefs, the Commission will order an independent consulting firm, to be selected by the Commission, to undertake a through review and make recommendations with regard to the several items of concern set forth above.

HANCOCK I

KU's witness, Mr. Tipton, proposed the inclusion of $3,445,554 in CWIP for test year funds expended on environmental studies, engineering studies, design studies and related expenses for the construction of the Hancock generating plant("Hancock").[84] As of June 30, 1982, KU reported that $7,820,000 had been expended in preparation for the construction of Hancock.[85] The Kentucky retail allocation for jurisdictional rate base is $6,425,890.

Opposition to the inclusion of the Hancock CWIP in KU's rate base was expressed by the AG, Willamette and Hancock County. Hancock County and the AG opposed the inclusion of Hancock CWIP on the ground that the Commission had not issued a certificate of convenience and necessity and thus that KU had not demonstrated need for power. Willamette opposed the inclusion of Hancock CWIP based on KU's inadequate load forecasting and capacity planning procedures resulting in investment commitments that are not reflective of prudent planning practices.[86]

In the Commission's Final Order in Case No. 8177, KU's management was placed on notice that the Commission expected the utility to study and pursue alternatives to the construction of the generation facility at Hancock. The Commission was of the opinion then and remains of the opinion that a utility which proceeds with a large generating unit during periods of high interest rates, uncertain economic conditions, escalating construction costs, uncertain need for the energy to be produced, and without an exhaustive consideration of less-costly alternatives invites financial instability and fails to meet the obligation which it has to its customers and shareholders.

Based on the record in this proceeding, the Commission is of the opinion that KU has made only a perfunctory effort at identifying conservation investment alternatives to the Hancock plant. In its conservation study KU was able to identify only a one-third horse power fan motor as a source of load savings for non-electric homes.(87) Without further investigation, conservation was rejected as a source of load savings for all other residential users based on KU's historical insulation standards for new construction. However, when asked what portion of KU's load is weather sensitive, Mr. Tipton testified, . . ."we do have a good bit of weather sensitive load . . ."(88) An examination of the load data supporting the KU cost of service study indicates a difference of over 800 MW between the maximum and minimum loads during January 1982 weekdays at 10:00 a.m.,(89) confirming Mr. Tipton's observation on weather sensitive load. In the opinion of the Commission, if KU is to reject conservation as an alternative to construction, it must identify conservation opportunities, and then subject the conservation option to a comparison of the marginal cost of saving a megawatt to the marginal cost of constructing a megawatt.

A number of utilities in Kentucky and the nation are participating in joint planning, construction and ownership of generation plant. This option permits a utility to better match its generation construction with load growth while enjoying the economies of scale associated with large base load plants. Mr. Bechanan rejected this expansion alternative by stating, "We have not gone with the theory of joint ownership. We feel that we can accomplish the same things by the sale or purchase of capacity."(90)

The Commission is aware from Case No. 8566(B), Setting Rates and Terms and Conditions of Purchase of Electric Power from Small Producers and Cogenerators by Regulated Electric Utilities, that KU plans for a 20 percent reserve margin. According to the current load forecast, when Ghent IV becomes operational in October 1984 KU winter reserve margin for 1984/85 will be equal to 55 percent.(91) Facing this reserve margin, KU has requested a pro forma revenue adjustment for its declining capacity sales to the KIP. When asked if decreased capacity sales would continue over the next 3 or 4 years, Mr. Tipton responded, "that looks like it would probably be the situation."(92) The Commission is concerned that KU's recent experience in capacity sales contradicts the basis of its rejection of joint ownership and KU appears to be committed to an independent course in its capacity planning and expansion regardless of the ultimate cost to the ratepayer.

The initial plans for the construction of the Hancock generation unit were formalized in 1977 with the first unit scheduled for completion in 1985.(93) Since that time the completion date has been rescheduled eight times, including a 4-year deferral since KU's last rate case. The current schedule calls for commercial operation in October 1993, over 10 years in the future. KU is only able to guess when it will seek a certificate of convenience and necessity.(94) The Commission is no longer convinced that the Hancock plant will be required within the foreseeable future if KU gives equal consideration to alternatives to Hancock construction. It is the opinion of the Commission that KU's expenditures on the Hancock plant are speculative in nature, and may not be the most economical method of meeting its service obligations. Since it seems doubtful that the investment in Hancock will ever be used and useful for providing service, the ratepayers should not now be required to provide a return on the investment made to date. It is therefore the decision of the Commission to exclude all jurisdictional CWIP related to Hancock from the rate base. Should the investment in Hancock become used and useful, KU would be allowed to recover through rates its reasonable construction costs.

SUMMARY

The Commission, having considered the evidence of record, is of the opinion and finds that:

1. The rates in Appendix A are the fair, just and reasonable rates for KU and will produce gross annual revenues based on adjusted test year sales of approximately $402,377,854.

2. The rates of return granted herein are fair, just and reasonable and will provide for the financial obligations of KU with a reasonable amount remaining for equity growth.

3. The rates proposed by KU would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

IT IS THEREFORE ORDERED that the rates in Appendix A be and they hereby are approved for service rendered by KU on and after March 12, 1983.

IT IS FURTHER ORDERED that the rates proposed by KU be and they hereby are denied.

IT IS FURTHER ORDERED that within 30 days from the date of this Order KU shall file with the Commission its revised tariff sheets setting out the rates approved herein.

IT IS FURTHER ORDERED that there be a thorough study of KU's load forecasting, and of such related issues as the benefits to be realized from a cost-effective conservation program; the most prudent course to follow concerning the Hancock units; the course to pursue with regard to cogeneration and small power production; and the extent to which it would be economically beneficial for KU to purchase power from and/or sell power to neighboring utilities, such study to be undertaken by an independent consulting firm to be selected by the Commission and compensated by KU, with the results of such study, and recommendations, to be contained in a report to the Commission, with copies made available to KU and other interested parties.

IT IS FURTHER ORDERED that KU shall begin capitalizing overheads as discussed in this Order in conformance with the Uniform System of Accounts.

Done at Frankfort, Kentucky, this 18th day of March, 1983.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Secretary

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 8624 DATED MARCH 18, 1983

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the date of this Order.

RS-1 Residential
Rural and Farm Residential Service*

RATE

Customer Charge $ 2.75 per month
Plus an Energy Charge of:
5.402 cents per KWH for the first 100 KWH used per month
4.943 cents per KWH for the next 300 KWH used per month
4.532 cents per KWH for all in excess of 400 KWH used per month

Minimum Bill: $ 2.75 per month for single phase service or $ 7.06 per month for three phase service, for all ordinary residential uses. Additional 85 ¢ per connected HP per month when special equipment, greater than normal investment, abnormal or seasonal use involved.

FERS
Full Electric Residential Service*

RATE

Customer Charge $ 3.75 per month
Plus an Energy Charge of:

4.588 cents per KWH for the first 1,000 KWH used per month
4.184 cents per KWH for all in excess of 1,000 KWH used per month

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* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

FERS (continued)
Full Electric Residential Service

Minimum Charge

Single phase service not less than \$ 3.75 per month
Three phase service not less than \$ 7.06 per month
For all ordinary residential uses of electric service, including those listed under Availability of Service. When the investment to serve the customer is greater than normal and/or where special electrical equipment is required by the Customer other than ordinary uses listed above, such as, but not limited to, large heating or motor loads, and/or when the use of the service will be seasonal or abnormal, the Company reserves the right to require a monthly minimum greater than that shown above in the amount of 85 cents per month per KW of connected load.

GS
General Service*

CHARACTER OF SERVICE

See Index Sheet for Character of Electric Service Available.

RATE

Customer Charge \$4.00 per month
Plus Energy Charge of:

6.920	cents per KWH for the first 500 KWH used per month
5.778	cents per KWH for the next 1,500 KWH used per month
5.301	cents per KWH for all in excess of 2,000 KWH used per month

Minimum Charge

Service under this schedule is subject to a minimum of the greater of (a) \$4.00 per month to include the first 20 KW or less of capacity, or (b) \$ 4.00 per month, plus \$ 1.69 per KW for demand in excess of 20 KW, which shall be determined from the greater of (1), (2), (3), or (4) as follows:

(1) The maximum demand registered in the current month
(2) 75% of the highest monthly maximum demand registered in the preceding 11 months
(3) The contract capacity, based on the expected maximum KW demand upon the system
(4) 60% of the KW capacity of facilities specified by the Customer.

GS

General Service (continued)

Minimum charge under (a), above, shall be billed on a monthly basis. Minimum charge under (b), above, shall be billed on a cumulative annual basis that starts on the month in which the meter was installed or service was first taken under the schedule. This is the beginning date of the contract year. Payments to be made monthly of not less than 1/12 of the annual minimum until the aggregate payments during the contract year equal the annual minimum. However, minimum payments made in excess of the amount based on the rate schedule will be applied as a credit on billings for energy used during the contract year.

O.P.W.H.

Off Peak Water Heating*

RATE

Customer Charge	$ 1.00	per month
Plus all energy at 3.618¢ per KWH per month		

MINIMUM MONTHLY CHARGE

The monthly minimum charge is the Customer Charge.

C.W.H.

Combination Off Peak Water Heating

APPLICABLE

In All Territory Served by the Company

AVAILABILITY OF SERVICE

For Domestic uses located on existing secondary lines of the Company when "Off-Peak" water heating is used in connection with an electric range of 8 kilowatts or more where customer cooks electrically.

CHARACTER OF SERVICE

The electric service furnished under this rate schedule will be single phase 60 cycle, alternating current, delivered from load centers at approximately 208 or 240 volts two wire, or 120, 208 or 240 volts three wire.

RATE

Customer Charge	$ 1.00	per month
Plus all energy at 3.011¢ per KWH per month		

* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

C.W.H.
Combination Off Peak Water Heating
(continued)

MINIMUM MONTHLY CHARGE

The monthly minimum is the Customer Charge.

DUE DATE OF BILL:

Customer's payment will be due within 10 days from date of bill.

FUEL CLAUSE

An additional charge or credit will be made on the kilowatt-hours purchased by the Customer in accordance with the fuel clause set forth on Sheet No. 24 of this Tariff.

FRANCHISE CHARGE

The rate herein provided shall include, where applicable, an additional charge for local government franchise payment determined in accordance with the Franchise Billing Plan as set forth in the Rules and Regulations of this Tariff.

TERMS OF SERVICE "OFF-PEAK" PERIOD

Service rendered under this schedule will be between the hours of 8:00 p.m. (at night) and 9:00 a.m. (next morning) E.S.T., except as otherwise permitted. Said period being understood as the "Off-Peak" period, and shall be subject to change from time to time as Company's peak load condition varies.

Each water heater is to be installed with and controlled by thermostat or thermostats and time switch (said time switch to be property of the Company when water heating connected load does not exceed 30 amperes) set and sealed by a Company representative so that "on" period of service will conform to "Off-Peak" period herein set forth. The Customer shall furnish and maintain time switch control equipment when water heating connected load is in excess of 30 amperes.

Service will be metered by a special sub-meter except under special conditions approved by the Company.

TERM OF CONTRACT

For a fixed term of not less than one year, and/or such time after the expiration of such fixed term until terminated by either party giving 30 days written notice to the other.

RULES AND REGULATIONS

Service will be furnished under Company's general Rules and Regulations or Terms and Conditions. See General Index for approved installation.

Rate 33 - Electric Space Heating Rider*

Rate: 4.252¢ per KWH

Minimum: $13.45 per connected KW but not less than $ 92.24 per heating season.

Rate A.E.S. (All Electric School)*

Rate: 4.255¢ per KWH

Annual Minimum: $20.12 per connected KW excluding air conditioning and equipment of one KW or less than $201.24per year.

IS
INTERRUPTIBLE SERVICE

APPLICABLE

In all territory served by the Company.

AVAILABILITY

This schedule shall be made available to any Customer receiving transmission service who contracts for not less than 4,000 KVA of his total requirements to be subject to either 200 or 400 hours interruption upon notification by the Company. Service under this schedule will be limited to customers whose firm capacity requirement does not exceed 10,000 KVA. Customers with firm capacity requirements that exceed 10,000 KVA will have a rate developed as part of their contract based upon their electrical characteristics.

Service at other than the Company's nominal transmission voltages will be available to Customers who contract to reimburse the Company for the additional facilities required beyond the transmission level.

RATE

Customer Charge:	$300 per month
Demand Charge:	
The firm capacity at:	$ 9.80 per KVA

* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

IS
INTERRUPTIBLE SERVICE
(continued)

Demand Charge: (continued)

Plus the KVA measured in excess of the firm capacity during the billing month at:

Subject to 200 hours interruption	$ 7.80 per KVA
Subject to 400 hours interruption	$ 7.30 per KVA

Plus an Energy Charge of:

1.931 cents for all KWH used in the billing month

Minimum Charges

The firm capacity will be based on the greater of:

(1) the firm capacity specified by the Customer's contract,
(2) the maximum load during any period of requested interruption in the billing month, or
(3) the maximum load during any period of requested interruption in the preceding 11 billing months.

INTERRUPTION

The Customer will, upon notification by the Company, reduce Customer's load being supplied by the Company to the firm level specified by contract

The total hours of interruption during any 12 consecutive months shall not exceed either 200 hours or 400 hours as agreed to by contract.

DUE DATE OF BILL: Customer's payment will be due within 10 days from date of bill.

FUEL CLAUSE

An additional charge or credit will be made on the kilowatt-hours purchased by the Customer in accordance with the fuel clause set forth on Sheet No. 24 of this Tariff.

FRANCHISE CHARGE

The rate herein provided shall include, where applicable, an additional charge for local government franchise payment determined in accordance with the Franchise Billing Plan as set forth in the Rules and Regulations of this Tariff.

IS
INTERRUPTIBLE SERVICE
(continued)

TERM OF CONTRACT

The term of contract shall be for an initial period of 10 years and shall continue thereafter until terminated by either party giving at least 7 years written notice to the other.

RULES AND REGULATIONS

Service will be furnished under the Company's general Rules and Regulations or Terms and Conditions, except as set out herein and/or any provisions agreed to by written contract.

L.P.
Combined Lighting and Power Service

APPLICABLE

In all territory served by the Company.

AVAILABILITY

This rate schedule is available for secondary, primary or available transmission line service on an annual basis for lighting and/or heating and/or power where no class rate is available.

It is optional with the Customer whether service will be billed under this schedule for the entire requirements, or under various other schedules applicable to the various services. The Customer having selected this schedule will continue to be billed under it for not less than 12 consecutive months, unless there should be a material and permanent change in the Customer's service.

Service under this schedule will be limited to maximum loads not exceeding 10,000 KW. If, at the effective date of this rate schedule, an existing Customer's load has exceeded 10,000 KW, service may be continued under this schedule until such time as the Customer's load exceeds the capability of the existing Company and/or Customer owned facilities; whereupon a new contract will be required, including a rate developed to cover the costs of service based upon the Customer's electrical characteristics. After the effective date of this rate schedule, Customers with new or increased load requirements that exceed 10,000 KW will have a rate developed as part of their contract based upon their electrical characteristics.

L.P.
Combined Lighting and Power Service
(continued)

CHARACTER OF SERVICE

The electric service furnished under this rate schedule will be 60 cycle, alternating current. The nominal secondary voltages delivered from load centers and the phase are as follows: Single phase, 120 volts, two wire, or 120/240 volts, three wire, or 120/208Y volts, three wire where network system is used. Where Company has three phase service available, such service will be supplied at 240, 480 or 208Y volts when delivered from network system. The nominal primary voltages of Company where available are 2400, 4160Y, 7200, 8320Y and 12,470Y volts.

RATE

Maximum Load Charge

Secondary Service at nominal voltages of 120, 240, 480 or 208Y as available.
$ 4.21 per kilowatt of the maximum load in the month, but not less than $ 505.20 per year.
Primary Service at nominal voltages of 2400, 4160Y, 7200, 8320Y and 12,470Y as available.
$ 3.21 per kilowatt of the maximum load in the month, but not less than $963.00 per year.
Transmission Line Service at voltages of 34,500 or 69,000 as available.
$ 3.04 per kilowatt of the maximum load in the month with minimum depending upon the facilities necessary to serve, but not less than $ 1,824.00 per year.

Plus an Energy Charge of

3.145 cents per KWH for the first 500,000 KWH used per month
2.896 cents per KWH for the next 1,500,000 KWH used per month.
2.766 cents per KWH for all in excess of 2,000,000 KWH used per month.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average KW demand delivered to the Customer during the 15 minute period of maximum use during the month.

The Company reserves the right to place a KVA meter and base the billing demand on the measured KVA. The charge will be computed based on the measured KVA times 90% of the applicable KW charge.

DETERMINATION OF MAXIMUM LOAD - (continued)

In lieu of placing a KVA meter the Company may adjust the measured maximum load for billing purposes when power factor is less than 90% in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum LW Load for Billing Purposes} = \frac{\text{Maximum KW Load Measured} \times 90\%}{\text{Power Factor (in percent)}}$$

MINIMUM ANNUAL BILL

Service under this schedule is subject to an annual minimum of $50.52 per kilowatt for secondary delivery.
$38.52 per kilowatt for primary delivery and $36.47 per kilowatt for transmission delivery for each yearly period based on the greater of (a), (b), (c), (d) or (e), as follows:

(a) The highest monthly maximum load during such yearly period.
(b) The contract capacity, based on the expected maximum KW demand upon the system.
(c) 60% of the KW capacity of facilities specified by the Customer.
(d) Secondary delivery, $505.20 per year; Primary delivery, $963.00 per year, Transmission delivery, $1,824.00 per year.
(e) Minimum may be adjusted where Customer's service requires an abnormal investment in special facilities.

Payments to be made monthly of not less than 1/12 of the Annual Minimum until the aggregate payments during the contract year equal the Annual Minimum. However, payments made in excess of the amount based on above rate schedule will be applied as a credit on billings for energy used during contract year. A new Customer or an existing Customer having made a permanent change in the operation of his electrical equipment that materially affects the use in kilowatt-hours and/or use in kilowatts of maximum load will be given opportunity to determine his new service requirements, in order to select the most favorable contract year period and rate applicable.

Rate HLF (High Load Factor)*

RATE

Maximum Load Charge	Secondary	Primary
All KW of Monthly Billing Demand	$ 5.27 per KW	$4.91per KW

Energy Charge: 2.534 ¢ per KWH for all KWH used.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average KW demand delivered to the Customer during the 15 minute period of maximum use during the month.

The Company reserves the right to place a KVA meter and base the billing demand on the measured KVA. The charge will be computed based on the measured KVA times 90% of the applicable KW charge.

In lieu of placing a KVA meter, the Company may adjust the measured maximum load for billing purposes when power factor is less than 90% in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum KW Load for Billing Purposes} = \frac{\text{Maximum KW Load Measured} \times 90\%}{\text{Power Factor (in percent)}}$$

Excess of 600 hours use of Billing Demand @ 2.534 cents per KWH

Rate MP-1 (Coal Mining Power Service)*

RATE

Maximum Load Charge
Primary Service at nominal voltage of 2400 or more--
$ 3.09 per kilowatt of the maximum load in the month.
Transmission Line Service at nominal voltage of 34,500 or more--$ 2.74 per kilowatt of the maximum load in the month.

Plus an Energy Charge of:
3.151 cents per KWH for the first 500,000 KWH used per month
2.801 cents per KWH for all in excess of 500,000 KWH used per month.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average KW demand delivered to the Customer during the 15 minute period of maximum use during the month.

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* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

Rate MP-1 (Coal Mining Power Service)*
(continued)

DETERMINATION OF MAXIMUM LOAD - (continued)

The Company reserves the right to place a KVA meter and base the billing demand on the measured KVA. The charge will be computed based on the measured KVA times 90% of the applicable KW charge.

In lieu of placing KVA meter, the Company may adjust the measured maximum load for billing purposes when power factor is less than 90% in accordance with the following formula:

$$\text{Adjusted Maximum KW Load for Billing Purposes} = \frac{\text{Maximum KW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

MINIMUM ANNUAL CHARGE

Not less than the greater (a), (b) or (c) as follows:

(a) $37.08 for primary delivery and $32.88 for transmission delivery for each yearly period for each kilowatt of capacity reserved by the Customer's application.

(b) $37.08 per kilowatt for primary delivery of $32.88 per kilowatt for transmission delivery, for each yearly period based on highest monthly maximum load during such yearly period.

(c) Not less than $ (to be determined by any special investment required to serve).

MONTHLY PAYMENTS

Each monthly bill shall be computed at the Maximum Load and Energy Charge set forth, however, in no event shall the aggregate payments at the end of any month during the contract year, including the current month's bill be less than the sum obtained by multiplying the number of months elapsed during the contract year by 1/12 of the annual minimum set forth. During subsequent months should the sum of the computed bills be less than the aggregate payments made, and greater than the minimum payments set forth above, adjustment shall be made on the basis of the sum of the computed bills, provided such adjustment shall not reduce the aggregate payments below the minimum payments set forth above.

DUE DATE OF BILL: Customer's payment will be due within 10 days from date of bill.

POWER FACTOR CLAUSE

All the Customer's apparatus shall be selected and used with reference to securing the highest practicable power factor.

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* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

Rate MP-1 (Coal Mining Power Service)*
(continued)

POWER FACTOR CLAUSE - (continued)

The Company shall have the right at all times to make an examination of the installation of motors and other apparatus of the Customer and it may refuse to make connection or to give service unless the installation is in proper condition to receive and is operated in such manner as to utilize safely and efficiently the energy furnished by the Company. The Customer shall not make any changes in his installation which will affect the operation of the Company's system without the consent of the Company.

The Company undertakes to supply the energy called for by this agreement at a power factor of approximately unity, but it will permit under the prescribed rates the use of apparatus which shall furnish during normal operation an average power factor not lower than 90% either lagging or leading, in the accepted technical meaning of these terms.

FUEL CLAUSE

An additional charge or credit will be made on the kilowatt-hours purchased by the Customer in accordance with the fuel clause set forth on Sheet No. 24 of this tariff.

FRANCHISE CHARGE

The rate herein provided shall include, where applicable, an additional charge for local government franchise payment determined in accordance with the Franchise Billing Plan as set forth in the Rules and Regulations of this Tariff.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a term of not less than 5 years, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to the expiration date.

RULES AND REGULATIONS

Customer must own and maintain or lease all transformers and other facilities necessary to take service at the delivered voltage.

Service will be furnished under the Company's general Rules and Regulations or Terms and Conditions, and under executed contract for electric service.

* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

Rate M (Water Pumping Service)*

RATE

Customer Charge $10.00 per month
1st 10,000 KWH 4.989 cents per KWH per month.
Over 10,000 KWH 4.256 cents per KWH per month.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be not less than the greater of (a), (b) or (c) as follows:

(a) The sum of $ .87 per horsepower for total rated capacity, of all motors or other apparatus connected, but not less than the Customer Charge.
(b) The sum of $ 1.74 per horsepower for total rate capacity, excluding standby power equipment and fire pumps.
(c) Based on required special investment.

Street Lighting Service Rate*

Incandescent System	Load/Light**	Rate Per Light Per Month Standard	Ornamental
1,000 Lumens (Approximately)	.102 KW/Light	$ 2.27	$ 2.93
2,500 " "	.201 KW/Light	2.78	3.58
4,000 " "	.327 KW/Light	3.98	4.92
6,000 " "	.447 KW/Light	5.30	6.35
10,000 " "	.690 KW/Light	7.15	8.74

Mercury Vapor	Load/Light**	Rate Per Light Per Month Standard	Ornamental
3,500 Lumens (Approximately)	.126 KW/Light	$ 5.76	$ 8.15
7,000 " "	.207 KW/Light	6.66	8.92
10,000 " "	.294 KW/Light	7.68	9.68
20,000 " "	.453 KW/Light	9.04	10.64
High Pressure Sodium			
5,800 Lumens (Approximately)	.083 KW/Light	$5.44	$ 8.06
9,500 " "	.117 KW/Light	6.14	8.94
22,000 " "	.242 KW/Light	9.07	11.87
50,000 " "	.485 KW/Light	14.64	17.44
Fluorescent			
20,000 Lumens (Approximately)	.489 KW/Light	$10.54	12.14

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* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.
** Refer to Determination of Energy Consumption Table.
# Restricted to those fixtures in service on February 15, 1977.
*** Restricted to those fixtures in service on October 12, 1983 (Except spot placement)

C.O.L. (Customer Outdoor Lighting Rate)**

	Load/Light**	Rate Per Lamp	
##2500 Lumen Incandescent Light	.201 KW/Light	$ 5.51	per month
3500 Lumen Mercury Vapor Light	.126 KW/Light	6.69	per month
7000 Lumen Mercury Vapor Light	.207 KW/Light	7.65	per month

P.O.Lt.
Private Outdoor Lighting

APPLICABLE

In all territory served by the Company.

AVAILABILITY

Service under this schedule is offered, under the conditions set out hereinafter, for lighting applications on private property such as, but not limited to, residential, commercial and industrial plant site or parking lot, other commercial area lighting, etc. to Customers now receiving electric service from the Company at the same location. Service will be provided under written contract signed by Customer prior to service commencing.

CHARACTER OF SERVICE

The Company will furnish a complete fixture with 2-foot mast arm for 8,600 lumen and 6-foot mast arm for other size lights on existing poles with available secondary voltage of 120/240. Service shall be from dusk to dawn totaling approximately 4,000 hours of annual burning time.

RATE

Monthly Charge	Approx. Lumens	Type Light	KW Rating
$ 6.66	8,600	Mercury Vapor	.214
$ 9.04	22,000*	Mercury Vapor	.468
$ 14.64	50,000*	High Pressure Sodium	.485

Note: *Not available for urban residential home use.

DUE DATE OF BILL

Payment will be due within 10 days from date of bill. Billing for this service to be made a part of bill rendered for other electric service.

** Refer to Determination of Energy Consumption Table.
Restricted to those fixtures in service on December 15, 1971

P.O.Lt.
Private Outdoor Lighting
(continued)

FUEL CLAUSE

An additional charge or credit will be made on the kilowatt-hours purchased by the Customer in accordance with the fuel clause set forth on Sheet No. 24 of the Tariff.

FRANCHISE CHARGE

The rate herein provided shall include, where applicable, an additional charge for local government franchise payment determined in accordance with the Franchise Billing Plan as set forth in the Rules and Regulations of this Tariff.

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 19 of the Tariff to which the fuel clause will apply.

TERM OF CONTRACT

For a fixed term of not less than 5 years and for such time thereafter until terminated by either party giving 30 days written notice to the other. Cancellation by Customer prior to the initial 5-year term will require the Customer to pay to Company its cost of labor to install and remove facilities plus cost of non-salvable material, prorated on the basis of the remaining portion of the 5-year period.

ADDITIONAL FACILITIES

Where the location of existing poles are not suitable or where there are no existing poles for mounting of lights, and the Customer requests service under these conditions, the Company may furnish the required facilities at an additional charge per month to be determined by the Company. These additional charges are subject to change by Company upon 30 days prior written notice.

All facilities required by Company will be standard stocked material. When underground facilities are requested and the Company agrees to underground service, the Customer will be responsible for ditching and backfilling and seeding and/or repaving.

RULES AND REGULATIONS

(1) Service shall be furnished under Company's general Rules and Regulations or Terms and Conditions, except as set out herein.

P.O.Lt.
Private Outdoor Lighting
(continued)

RULES AND REGULATIONS - (continued)

(2) All service and necessary maintenance on the light and facilities will be performed only during regular scheduled working hours of the Company. The Company shall be allowed 48 hours after notification by the Customer in which to restore service.

(3) The Customer shall be responsible for fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts.

(4) The Company shall own and maintain all facilities required in providing this service.

Lighting KWH
DETERMINATION OF ENERGY CONSUMPTION

APPLICABLE

Determination of energy set out below applies to Street Lighting Sheet No. 17, Private Lighting Sheet No. 18 and Customer Outdoor Lighting Sheet No. 18.1.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415

TOTAL FOR YEAR 4,000 HRS.

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Rider For Welding and Other Intermittent and Fluctuating Loads

APPLICABLE

In all territory served by the Company.

AVAILABILITY

The Company's Rules and Regulations contain the following provisions covering Power Factor and Protection of Service:

Rider For Welding and Other Intermittent and Fluctuating Loads (continued)

POWER FACTOR

"Where the Customer has equipment installed that operates at low power factor the Company reserves the right to require the Customer to furnish, at his own expense, suitable corrective equipment to maintain a power factor of 90% lagging or higher."

PROTECTION OF SERVICE

"The Company cannot render service to any Customer for the operation of any device that has a detrimental effect upon the service rendered to other Customers."

"The Company, however, will endeavor to cooperate with its Customers when consulted concerning the intended use of any electrical device."

"Where the Customer's use of service is intermittent or subject to violent fluctuations, the Company reserves the right to require the Customer to furnish, at his own expense, suitable equipment to reasonably limit such intermittence or fluctuation."

When compliance with the Company's Rules and Regulations requires the Customer to furnish corrective equipment for the purpose of protecting service to Company's other Customers by increasing the power factor of and/or reducing the intermittence or fluctuations in the Customer's use of service (such as may be the case when the Customer's load includes welding equipment, electric arc furnaces, etc.), the Company, by the provision of special supply facilities, may be able to eliminate the necessity for Customer furnished corrective equipment. If the estimated cost of Company provided special supply facilities is less than the cost of Customer provided corrective equipment, the Company may give the Customer special permission to operate specified abnormal load, consisting of low power factor, intermittent or widely fluctuating loads, without correction, in which case the Customer will pay the following rate to the Company:

RATE

1. A lease or rental charge on all special or added facilities, if any, necessary to serve such loads.

2. Plus the charges provided for under the rate schedule applicable, including any customer charge if applicable, energy charge, maximum load charge (if load charge rate is used), fuel clause and the minimum under such rate adjusted in accordance with (a) or (b) herein.

Rider For Welding and Other Intermittent and Fluctuating Loads (continued)

RATE - (continued)

(a) If rate schedule calls for a minimum based on the total KW of connected load, each KVA of such special equipment shall be counted as one KW connected load for minimum billing purposes.

(b) If rate schedule calls for a minimum based on the 15 minute integrated load, and such loads operate only intermittently so that the KW registered on a standard 15 minute integrated demand meter is small in comparison to the instantaneous load such equipment is capable of imposing, each KVA of such special equipment shall be counted as one-third KW load for minimum billing purposes.

MINIMUM

As determined by this Rider and the Rate Schedule to which it is attached.

This schedule applies to all new loads; also to existing load where such existing loads now or hereafter have a detrimental effect upon the electric service rendered to other Customers of the Company.

Optional Minimum Rider To Any Applicable Rate Schedule For Seasonal and/or Temporary Electric Service

Minimum: $ 4.21 per KW per month of total connected load

AVAILABILITY OF SERVICE

This rider is available at the option of the Customer where Customer's business is of such nature to require only seasonal service or temporary service, including service provided for construction of residences or commercial buildings, and where in the judgment of the Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other Customers.

This service is available for not less than one month (approximately 30 days), but when service is used longer than one month, any fraction of a month's use will be prorated for billing purposes.

Special Contract for Electric Service to Green River Steel Corporation*

Demand Charge:

Non-Interruptible Demand	$ 4.22 per KW
Interruptible Demand	1.97 per KW
Additional Demand	0.97 per KW

Plus an Energy Charge of:

A. For KWH used between 6 a.m. and 10 p.m., Monday-Friday, excluding holidays:

24.65 mills per KWH

B. For all KWH used at other hours:

23.24 mills per KWH used

Reactive Demand Charge:

$0.241 per RKVA

Annual Minimum: $ 386,766

Special Contract for Electric Service to West Virginia Pulp & Paper Company*

Demand Charge:

Non-Interruptible	$ 3.79 per KVA, but not less than 10,000 KVA
Interruptible	1.81 per KVA

Plus an Energy Charge of:

23.63 mills per KWH for all KWH used.

Annual Minimum:

$ 45.48 per KVA of maximum non-interruptible demand
$ 21.72 per KVA of maximum interruptible demand but not less than $807,500 per said 12 month period

* An additional charge or credit will be made on the kilowatt-hours purchased by the customer in accordance with the fuel clause.

RULES AND REGULATIONS OR TERMS AND CONDITIONS
Applicable to All Classes of Electric Service

DISCONTINUANCE OF SERVICE

The Company is authorized to refuse or discontinue service to any Applicant or Customer for (a) noncompliance with these Rules and Regulations, (b) for refusing or neglecting to provide reasonable access to the premises, (c) when the Applicant is indebted to the Company for service, (d) for noncompliance with any applicable state, municipal, or other code, rule or regulation, (e) for nonpayment of bills, or (f) for fraudulent or illegal use of service. The Company shall discontinue service when a dangerous condition is found to exist on the Customer's premises. Service shall be so refused or discontinued in accordance with the provisions of Kentucky Public Service Commission Regulation 807 KAR 5:006 Section 11 (as may be modified or replaced by any regulation hereafter adopted governing discontinuance of service), which is hereby incorporated herein as a part of these Rules and Regulations. A copy of such Commission Regulation shall be furnished to any Applicant or Customer upon request.

When service has been discontinued for any of the reasons stated above, service shall not be restored until the Company has been paid in full for the cost of service rendered (which may be estimated by the Company if actual usage cannot be determined) and reimbursed for the estimated cost to the Company incurred by reason of the discontinuance, and if service is restored, for reconnection. For any Customer whose service has been discontinued for nonpayment of bills, \$10.50 shall be charged for reconnecting service during regular scheduled working hours and \$38.00 for reconnecting service during other than regular schedule working hours.

When service has been discontinued for any of the above reasons, the Company shall not be responsible for any damage that may result therefrom.

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to the Company.

RULES AND REGULATIONS OR TERMS AND CONDITIONS
SPECIAL CHARGES

The following charges will be applied uniformly throughout the Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to meet associated expenses.

RULES AND REGULATIONS OR TERMS AND CONDITIONS
SPECIAL CHARGES
(continued)

RETURNED CHECK CHARGE

In those instances where a Customer renders payment to the Company by check which is not honored upon deposit by the Company, the Customer will be charged $ 5.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a Customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter was not more than two percent fast, the Customer will be charged $ 14.00 to cover the test and transportation costs.

RECONNECTION CHARGE

To reconnect a service that has been disconnected for nonpayment of bills or for violation of the Company's Rules and Regulations, the Customer will be charged $ 10.50 for reconnection during regular scheduled working hours or $ 38.00 for reconnection at any other time.